STATE OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

NSTAR Electric	)	Docket No. 03-121

Direct Testimony of

THOMAS S. MICHELMAN

on behalf of the

CONSERVATION LAW FOUNDATION

and the

SOLAR ENERGY BUSINESS ASSOCIATION OF NEW ENGLAND

March 16, 2004

I. INTRODUCTION AND QUALIFICATIONS

Q. Please identify yourself.

A. I am Thomas S. Michelman, President of Thomas S. Michelman Inc. and Principal of Boreal Renewable Energy Development ("Boreal"). Boreal is a Massachusetts partnership of Thomas S. Michelman Inc and Robert A. Shatten Inc. with offices at 6 Magnolia Drive Acton, Massachusetts. Thomas S. Michelman Inc. is a Massachusetts Corporation with offices at 6 Magnolia Drive Acton, Massachusetts.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Conservation Law Foundation (CLF) and the Solar Energy Business Association of New England (SEBANE).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to set out recommendations regarding NSTAR's proposed Standby Rates from the perspective of wind development.

Q. Please state your qualifications.

A. I have been intimately involved with the electric industry in New England for over eleven years. From 1993 to 2003 I worked as a consultant for XENERGY Inc (now KEMA Consulting) in Burlington, Massachusetts. My practice area included analysis of efficiency, renewable and load response programs, and retail and wholesale markets. Clients included utilities, competitive suppliers, public agencies, system operators. An important part of my work included deciphering and analyzing the impact of utility rates. In the summer of 2003 I co-founded Boreal Renewable Energy Development which focuses on the Distributed Generation (DG) wind energy development and consulting in New England. I created Thomas S. Michelman, Inc. I received a B.A. in Mathematical Methods in the Social Sciences in 1983 from Northwestern University in Evanston, Illinois, and M.S. in Resource Economics in 1993 from the University of Rhode Island, in Kingston, Rhode Island.

II. SUMMARY

Q. What is your overall recommendation?

A. The proposed rates have subtle, but significant negative effects on Wind DG development. I recommend that the Department disapprove the NSTAR's proposed Standby Rates.

Q. How is your testimony organized?

A. My testimony is organized into the following sections:

1. Introduction and Qualifications
2. Summary
3. Review of NSTAR's Standby Rate Proposal
4. Standby Rate Proposal's Effect on DG Wind Project Economics
5. Potential Public Benefits of DG Wind
6. Conclusion

III. REVIEW OF NSTAR RATE STANDBY RATE PROPOSAL

Q. What is your overall view of the proposed NSTAR Standby Rates?

A. NSTAR's proposed Standby Rates would change the structure of distribution rates for customers who install new DG applications (e.g., by transforming energy charges into demand charges for Commonwealth G-2, and G-3 tariff classes). Thus, the proposed rate would treat customers with DG differently than customers without DG, and would discriminate against customers with DG applications. The proposed rates are inappropriate for customers with intermittent DG technology such as wind. Customers with wind DG pay their fair share of distribution costs under the current rate structure, and the proposed rate structure will discourage deployment of wind DG, resulting in a loss of environmental and other benefits.

Q. Why do customers with wind DG pay a fair share of distribution costs under the current rate structure?

A. Because wind DG does not have a large effect on the customer's monthly peak metered demand.

Q. Why not?

A. Because of the basics of wind power. Most modern wind turbines do not start producing electricity until the wind speed reaches 3 meters/second (m/s or 6.7 mph), and generally only produce less than 10 percent of their nominal output at speeds up to 5 m/s. In a very good wind regime of an average wind speed of 7 m/s, the wind speed is 5 m/s or less about 25 percent of the time.

Q. So what does this imply for monthly peak metered demand?

A. It means that the monthly peak metered demand post DG wind installation likely will be equal to or within 5 percent of the monthly peak metered demand pre DG wind installation. The exact effect for any specific customer depends upon characteristics of customer load, wind resources, and type and size of wind turbine installation. However, even in an unlikely scenario where a customer installs a wind turbine with a peak production of more than four times their on-site consumption, monthly peak metered demand will diminish between 2 and 10 percent over a twelve month period.

Q. Could you provide a specific example?

A. An example is set out in Exhibit 1. This shows the modeled impact on monthly metered demand for a Commonwealth G-2 customer with the class average load profile under various wind DG scenarios. This example compares the demand without a turbine to the demand after installation of various turbines manufactured by Fuhrlander (FL). As can be seen in Exhibit 1, even installing a 1000 kW turbine for a hypothetical G-2 customer with annual peak demand of 232 kW only slightly decreases the monthly metered demand that is used to calculate distribution charges. In this scenario, the customer would pay $3,317.96 annually for distribution demand charges without a turbine, and $3,267.73

annually if they installed a turbine with a nominal peak output of 1000 kW (the FL-1000 kW).

Q. Will this result hold if more wind DG is installed at the same site?

A. Yes very closely, as the wind does not blow strongly enough to generate much electricity a significant fraction of the time. Simply put: No wind, no electricity produced, same monthly metered demand as prior to the installation of a wind turbine.

Q. How should intermittent renewable DG such as wind be treated for purposes of distribution rate design?

A. Wind DG is akin to energy conservation measures or just normal variations in customer load. These technologies do not belong on standby rates such as those proposed by NSTAR.

IV. STANDBY RATE PROPOSAL'S EFFECT ON DG WIND PROJECT ECONOMICS

Q. In general how do wind turbines provide economic value?

A. In Massachusetts, there are three revenue streams from DG wind installations: 1) reducing competitive generation and utility charges as a result of consuming DG wind production on-site, rather than consuming electricity transported through ISO-NE transmission and the local utility distribution system; 2) selling excess production from the DG wind turbine not consumed on-site; and 3) selling the Renewable Energy Credits (RECs) from the DG wind turbine production. As described above, a DG wind system will reduce monthly metered demand only minimally. Obviously a DG wind installation will not avoid monthly customer charges. So a DG wind installation can only reduce charges associated with energy (kWh) consumption. All things being equal, the higher the energy charges on per kWh basis, the more appealing the project economics.

Q. Does the amount of wind resources affect the project economics?

A. Yes to a great degree. The difference between bad and good wind resources in most cases is the difference between a non-viable and viable project on an economic basis. In the NSTAR service territory, Cambridge has little or no economically viable locations for current wind technology; BECO has some viable locations; and the Commonwealth territory likely has the best overall wind resources of any territory in Massachusetts. Thus any rate changes in the Commonwealth territory are of extreme importance to those interested in development of wind technology in Massachusetts and New England.

Q. NSTAR has proposed different Standby Rates for their three companies Boston Edison (BECO), Cambridge Electric Company (Cambridge), and Commonwealth Electric Company (Commonwealth). How do these proposals differ?

A. A close examination of NSTAR's rates show that current rate structure varies widely from BECO to Cambridge to Commonwealth. The important difference is whether the distribution charges include energy (kWh) and demand charges (kW or kVa) or just demand charges.

Q. How do they vary?

A. For BECO, the rate classes generally associated with the largest consumption and demand, T-2 and G-3, have tariffs that only include demand based distribution charges. The distribution charges for these classes are currently structured so that they impose a large disincentive to DG wind installation.

Q. How do the other proposed rates compare?

A. BECO's G-2, Cambridge's G-2, and Commonwealth's G-2 and G-3 rate classes include both energy (kWh) and demand (kW or kVa) distribution based charges. The proposed Standby Rates transform all the distribution energy charges into demand charges. For example Commonwealth G-2 customers currently pay 0.0593 ¢/kWh to 1.403 ¢/kWh (depending on load period) and $1.53 /kVa per month for distribution charges. With the proposed Standby Rates, those customers would pay 0.000 ¢/kWh and $4.97/kVa.

Q. Looking at BECO's G-2, Cambridge's G-2, and Commonwealth's G-2 and G-3 rate classes, how does the proposal to transform distribution energy charges into distribution demand charges discourage the installation of Wind DG systems?

A. These proposed rates deter DG wind projects in at least three ways: 1) The proposed rate structure reduces incentives to install larger rather than smaller turbines.

2) The proposed Standby Rate structure provides disincentives to customers with lower load factors to install wind turbines.

3) The proposed Standby Rate structure takes away an easily identifiable benefit of installing a wind DG system.

Q. How does the proposed Standby Rate structure reduce incentives to install larger turbines?

A. Under the current rate structure, DG installations will reduce distribution energy charges for each kWh produced by the turbine. For example, assuming the wind is randomly distributed over all hours of the year and all the output of the turbine is consumed on-site, then the weighted average of reduced distribution energy charges is 0.874 ¢/kWh for the current Commonwealth G-2 rate structure, and, of course, 0.0 ¢/kWh for the proposed Standby Rates (see Exhibit 2). The proposed rate structure will reduce the customer’s benefits of the wind turbine installation by approximately 0.874 ¢/kWh for each additional kWh of energy produced by the turbine and consumed on site (the exact amount saved by the customer will depend on many factors including the customers load profile, the wind regime on site the model of turbine installed).

Q. Does the Standby Rate remove all incentives to install a larger turbine?

A. No. There is a slight incentive to increase the kW size of the turbine because of the slight decrease in distribution demand charges as the turbine size increases. However, the proposed Standby Rate removes the bulk of the incentives for installing a larger turbine. Given the capital cost associated with installation of such a turbine this reduction in economic incentives will result in fewer projects of this type being constructed and thus less generation of power from these distributed and non-emitting sources.

Q. Can you provide some examples of what these distribution charge impacts might be in practice?

A. Yes, under a reasonable set of assumptions about the turbine system installed, the energy consumption and demand on-site, the wind regime, the utility charges, etc. There are two general things to keep in mind. First, as wind turbines get bigger their installed cost / kW generally decreases. Second, as the turbines get bigger an ever increasing portion of the turbine production is sold back into the grid, rather than consumed on-site. Since decreasing energy consumption on-site means decreasing on-site generation, transmission, transition, energy efficiency, renewable, and potentially distribution charges (with the current rate structure, and not with the proposed Standby Rates), all things being equal it is more beneficial for the customer to consume production on-site than to sell DG production at wholesale market prices.

Q. Please continue.

A. Please look at Exhibit 3 (Commonwealth G-2 prototypical customer) and Exhibit 4 (Commonwealth G-2 prototypical customer). These Exhibits show basically the same pattern. Under current rates, as the turbine size increases the distribution charges decrease by large amounts. Under the proposed Standby Rate structure, increases in turbine size result in only minimal decreases in distribution charges.

Q. In Exhibit 4 (G-3 Commonwealth customers) doesn't it show that the customer is better off with the proposed Standby Rate structure rather than the current rate structure, because for every turbine scenario shown in Exhibit 4 the modeled customer will pay less distribution charges under the proposed Standby Rates than under the current rate structure?

A. For the G-3 prototypical customer modeled that is correct, but the results are an artifact of the load profile used in the example. The utility class average load profiles used for these analyses are the class load profiles found on the NSTAR website (http://www.nstaronline.com/your_business/load_profile/util_load_town.asp?lk=ucaorsls). Averaging many different profiles into one class average profile results in a smoother load shape with a higher load factor than that of the average customer. So the average a customer with energy consumption similar to the prototypical customer characterized by the utility class average load profile will have a lower load factor than the utility class average load profile used in these analyses. The average customer, because of the lower load factor, will pay relatively more in demand charges.

Q. How does the proposed Standby Rate structure provide disincentives to customers with lower load factors to install wind turbines?

A. NSTAR is proposing to transform distribution energy to distribution demand charges for BECO's G-2, Cambridge's G-2, and Commonwealth's G-2 and G-3 rate classes. NSTAR is proposing this structural change for only a fraction of customers in these rate classes, only for (and discriminating against) those installing DG systems. Clearly a customer with a lower than average load factor installing a wind DG system would end up paying relatively more demand charges than a high load factor customer for the proposed Standby Rates. These increased rates for the low load factor customers are an unnecessary barrier for wind DG.

Q. How does the proposed Standby Rate structure take away an easily identifiable benefit of installing a wind DG system?

A. Under the current rate structure, the benefits of a decrease in distribution energy charges associated with on-site consumption is one of the incentives being offered to customers to encourage them to further the Commonwealth's policies of fostering clean, non-polluting, renewable energy resources. With the proposed Standby Rate structure, there would be no distribution energy charges, and therefore no distribution charge reduction to customers for installing wind DG – removing that incentive.

V. POTENTIAL SYSTEM BENEFITS OF DG WIND POWER

Q. Does Wind DG have benefits beyond the direct project economics?

A. Yes, many. They potentially include reduction of environmental impacts, decreasing winter peak demand, decreasing summer peak demand, reducing line losses, reducing ISO-NE system prices, decreasing energy price risk and job retention and creation.

Q. How might the installation of a wind DG project improve environmental quality?

A. Wind energy is a non-polluting generation source and it does not utilize fossil fuels. It, along with other renewable power, can displace the marginal fossil-based generation source off of the grid (or prevent its dispatch), thus reducing the amount of CO_2, SO_2, NO_x, and other pollutants discharged by these facilities. Exhibit 5 shows the 2002 Marginal Emission Rates for CO_2, SO_2, NO_x for ISO-NE, and thus the potential mass of pollution reduction per MWh of wind energy production. Exhibit 5 also includes the potential emission reductions for a 250 kW and 1000 kW turbine with a 30% capacity factor (i.e., the turbine generates 30% of it annual maximum theoretical output), which would be typical of a good wind regime.

Q. How might the installation of a wind DG project reduce winter system peak demand?

A. Conduction, convection and air infiltration are the factors that affect building heat loss in the winter. In most cases conduction and infiltration are the primary causes of building heat loss. Wind speed is a primary contributor to air infiltration rates in buildings. So basically, the faster the wind blows the more heating required. All things being equal a cold windy day will require more heating of buildings, than cold non-windy days. Of course on windy days the wind turbine generates electricity which would likely be coincident with the highest winter demand.

Q. What if the wind was not blowing coincident with system or local distribution peak, would it still have a benefit?

A. Yes. The peak demand problems this winter for the generation grid were to a great degree cumulative and associated with the lack of natural gas as an input to combined cycle generation. Any wind turbine generation in the days prior to the peak demand would have in all likelihood displaced some combined cycle generation, thus decreasing the amount of natural gas consumed and increasing the supply available during the system peak.

Q. How might the installation of a wind DG project reduce summer system peak demand?

A. Most of the best wind resources in the NSTAR territories are close to the coastline. Peak demand during the summer usually occurs during hot summer afternoons. This is the same time when offshore winds blow strongest. That is, the land mass heats up during the hot summer day, hot air rises over land, and the cooler ocean air rushes in over land, which would induce wind turbine electricity production.

Q. How might the installation of a wind DG project reduce line losses?

A. Line losses are a proportional to the current squared. Any decrease in demand and in the current needed by a customer because of their on-site generation will decrease the line losses for all customers.

Q. How might the installation of a wind DG project reduce ISO-NE system prices?

A. DG wind installations would in all likelihood be "price-takers." Any increase in price-taking supply would only increase the probability of not dispatching the marginal unit with the highest prices in the ISO-NE system, and could only decrease wholesale prices or at worse keep them at the same level.

Q. How might the installation of a wind DG project reduce price risk?

A. As the Commission is fully aware energy prices have fluctuated widely and generally increased over the past few years. Clearly the installation of a wind DG system that offsets a large fraction of energy consumption on-site and has no fuel costs will decrease the total energy volatility for the customer. If the wind DG system produces 50 percent of the energy consumed on-site, then any increases in energy costs (or other costs associated assessed on a kWh basis) would be mitigated by 50 percent.

Q. How might the installation of a wind DG project assist in job creation and retention?

A. During the planning, design, and construction phases numerous people would be employed to facilitate each phase. After commissioning of the turbine, only minimal operations and maintenance staff would be needed. Jobs might be retained as organizations that have installed a wind turbine would be less likely to move operations because of the economic benefits associated with the installation, and the decreased risk of electricity costs.

VI. CONCLUSION

Q. In summary, how do you view NSTAR's Standby Rate proposal?

A. In summary, the proposed Standby Rate discriminates against low load factor customers, takes away incentives for installing larger turbines at a customer site, and makes it harder for someone to advocate for a turbine installation by transforming energy charges into demand charges. Under the current rate structure. wind DG systems would have little impact on the distribution revenue received by NSTAR. Further as just described, wind DG should be promoted not hindered because it furthers state environmental and energy policy, has numerous potential wide ranging benefits including reducing pollution, mitigating winter and summer peak demand, reducing ISO-NE system prices, decreasing distribution line losses, and job creation and retention.

Q. Does this conclude your testimony?

A. Yes, it does.

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EXPERIENCE THUMBNAIL

Boreal Renewable Energy Development, Acton, MA: Principal, August 2003 to Present. With partner, started up firm focusing on distributed generation wind energy development at commercial and institutional customer sites. Co-led successful bid for $100,000 proposal for a wind feasibility study for the Town of Barnstable. Identified large electricity consumers in good wind resource area for target customer list. Marketed services to targeted customers with over a fifty percent agreeing to a sales visit. Created sophisticated *pro forma* scenario tool to quickly and accurately assess project financials for prospective customers.

Currently performing a comprehensive review of available wind turbine technology in terms of its economic, siting and performance for the Cape Cod Commission and Cape Light Compact of Cape Cod, Massachusetts. Information to be synthesized and integrated in Cape-wide planning efforts for the optimal adoption of wind turbines.

KEMA-XENERGY Inc., Burlington, MA: Senior Professional, January 1993 to July 2003. Progressed from entry-level analyst to senior project / client management and sales development position specializing in retail energy, price responsive load, demand side management, and renewable energy. Responsibility managing millions of dollars of consulting projects. Key developer of retail energy consulting practice. Leveraged multi-client subscription studies as springboard to over $3 million of new consulting work. Considered industry expert in retail energy field, presenting at dozens of conferences and meetings, and authoring dozens of articles and reports.

University of Rhode Island, Kingston, RI: Economic Research Assistant, 1989 to 1991.

National Perinatal Information Center, Providence, RI: Consultant / Research Analyst, 1986 to 1990.

Putnam, Hayes and Bartlett, Cambridge, MA: Analyst/Network Administrator, 1985 to 1986.

FIELDS OF SPECIAL COMPETENCE

• Energy Industry Restructuring	• Renewable Energy
• Price Responsive Load Analysis	• Forecasting Competitive Market Activity
• Statistical Analysis	• DSM Program Evaluation
• Market Research	• Survey Design and Implementation

• Multivariate Modeling	• Load Research
• SAS Programming	• Excel, Word, PowerPoint

EDUCATION

M.S., Resource Economics, University of Rhode Island, 1992 (Thesis, *Contingent Valuation and the Bounded Rationality Perspective* winner of award of merit at AAAE and NAREA conferences.)

B.A., Mathematical Methods in the Social Sciences/Political Science, Northwestern University, 1983.

EXPERIENCE HIGHLIGHTS

Originator, managing editor, and contributor of XENERGY's *Retail Energy Foresight*. Bimonthly periodical publishes the only comprehensive updates on U.S. retail energy switching. From scratch managed concept, website development, online subscription tracking and billing, and issue layout. Each issue forecasts customer migration rates, and analyzes market activity and political or regulatory dynamics that shape the retail environment. Efforts brought in over $200,000 of additional revenue, 50 new clients and thousands of new contacts via trial subscriptions in untapped market segment, while repackaging on-hand knowledge and content (http://www.xenergy.com/foresight).

Project Manager and contributor to analysis of renewable / sustainable energy projects in 2003. Managed and contributed to three "sister" reports: *An Assessment and Report of [Distributed Generation / Load Management / Electric Conservation] Opportunities in Southwest Connecticut*._ (http://www.sustainenergy.org/publication/reports.asp). Provided analysis and support to the Massachusetts Technology Collaborative for their involvement in the NGrid GreenUp program and Massachusetts Green Power Partnership. Led an evaluation of the commercial renewable program for Wisconsin Focus on Energy.

Manager of market research for first five years of annual multi-client, multi-phase project on competitive electric and gas restructuring. Immersed in "soup-to-nuts" creation, testing, implementation, analysis and reporting of telephone and mail surveys. Typical cycle included 3 markets with 6 or more surveys, each of hundreds of customers. Respondents ranged from small residential to large industrial consumers. Analysis has included simple presentation of results in tabular and graphical format to multi-nomial logit modeling of customers' decision of supplier. Integrated research on competitors and market structure to provide complete story of research results.

For numerous clients have **managed and assessed retail market viability**. Assignments of $100,000+ include:

- For company seeking to enter retail electric and gas markets, part of three person team that developed comprehensive financial and market entry models (and associated strategy) to evaluate opportunities by service territory. Modeled the cost structure and revenue streams of retail suppliers under varying business-planning scenarios.

- For litigation support, led research and analysis team predicting the amount of customer load migration for a five-year horizon given a baseline year regulatory market structure. Compiled, categorized and scored factors affecting retail market appeal. Modeled migration rates as a function of shopping credits and non-price score. Predicted future migration as a function of future market attributes.
- Managed surveys and analysis of potential retailers, aggregators, and customers to inform predictions of customer migration of utilities facing impending retail competition.
- Researched and authored 5 to 30 page "briefs" of regulatory and market structure for a dozen states with retail choice.

Participated in, researched, and analyzed electric **price responsive load programs**. For pilot project led initiative of bidding strategy system to maximize revenue for NYISO demand response program as curtailment service provider. For ISO-NE worked on development of framework and analyzed impacts of implementing a price-responsive load program in transforming wholesale market environment. For California Energy Commission analyzed foundations, strengths and weaknesses of baselines used to calculate demand response levels and program impacts. For investor owned utility (IOU) researched and compared other IOU demand response programs to bolster regulatory filing. For various IOUs, evaluated quantitative impact of load response programs.

Performed **quantitative impact analysis** for dozens of **Demand Side Management (DSM) evaluations**. Executed billing analyses for numerous electric and gas DSM programs, including large-scale multi-measure, new construction, low-income and multi-fuels programs.

SELECTED ENERGY RELATED PAPERS / PUBLICATIONS / PRESENTATIONS

At invitation of industry conference organizer Infocast, have created and presented at more than a half dozen sessions as retail energy market expert. Session lengths varied from thirty-minute overview to four-hour workshop.

<u>Switching Trends</u> column in *Retail Energy Foresight*, and author / contributor to numerous additional articles and analyses. 2000 to 2003.

Bi-weekly column in *Power Executive* entitled <u>Texas Insider</u>. 2002.

Forecasting the Backcast: Daily Response Strategy for an Emergency Demand Response Program, T. Michelman. Presented at EPRI Forecasting Symposium. November 2001 Nashville, TN.

Real Prices, Real Responses: Results from a New York Real Time Price Program, T. Michelman. Presented at Price-Responsive Load Management: A New Opportunity in New York State Electricity Markets. March 2001 Albany, NY.

Modeling and Predicting Retail Electric Switch Rates, T. Michelman and M. Goldberg. A White Paper of XENERGY's Retail Energy Foresight. June 2000.

Factors Affecting Robust Retail Energy Markets, T. Michelman. Published in *The Electricity Journal*, April 1999.

Deregulation Elsewhere, T. Tschamler and T. Michelman. Published in *Deregulation* a special report published by the Illinois Manufacturers' Association, 1999.

Flops to Tops: Factors Affecting Robust Energy Markets, T. Michelman. Presented at the 9th National Energy Services Conference and Exposition, December 1998.

Transforming Dusty, Self-Selected Audit Data into Shiny New Population Estimates of Energy, T. Michelman, M. Goldberg, A. Loose. Presented at the 1997 International Energy Program Evaluation Conference.

Gold or Gold Plated? Benefit-Cost Analyses of Differing Metering Methods and Durations, C. Quackenbush, T. Michelman, M. Goldberg, S. Manwell. Presented at the 1997 International Energy Program Evaluation Conference.

Load-Based Customer Segmentation Using Hourly End-Use Data, T. Michelman and A. Parece. Presented at the 1996 Association of Edison Illuminating Companies (AEIC) Annual Load Research Conference.

Commercial and Industrial Customer Perceptions of Electric End-Use Consumption: A Comparison with Audit-Based Estimates, A. Parece and T. Michelman. Presented at the 1996 American Council for an Energy-Efficient Economy Summer Conference.

Exhibit 1 –
Comparison of Monthly Metered Peak kW for a Customer with a Commonwealth G-2 Load Profile for Various Fuhrlander (FL) Turbine Sizes

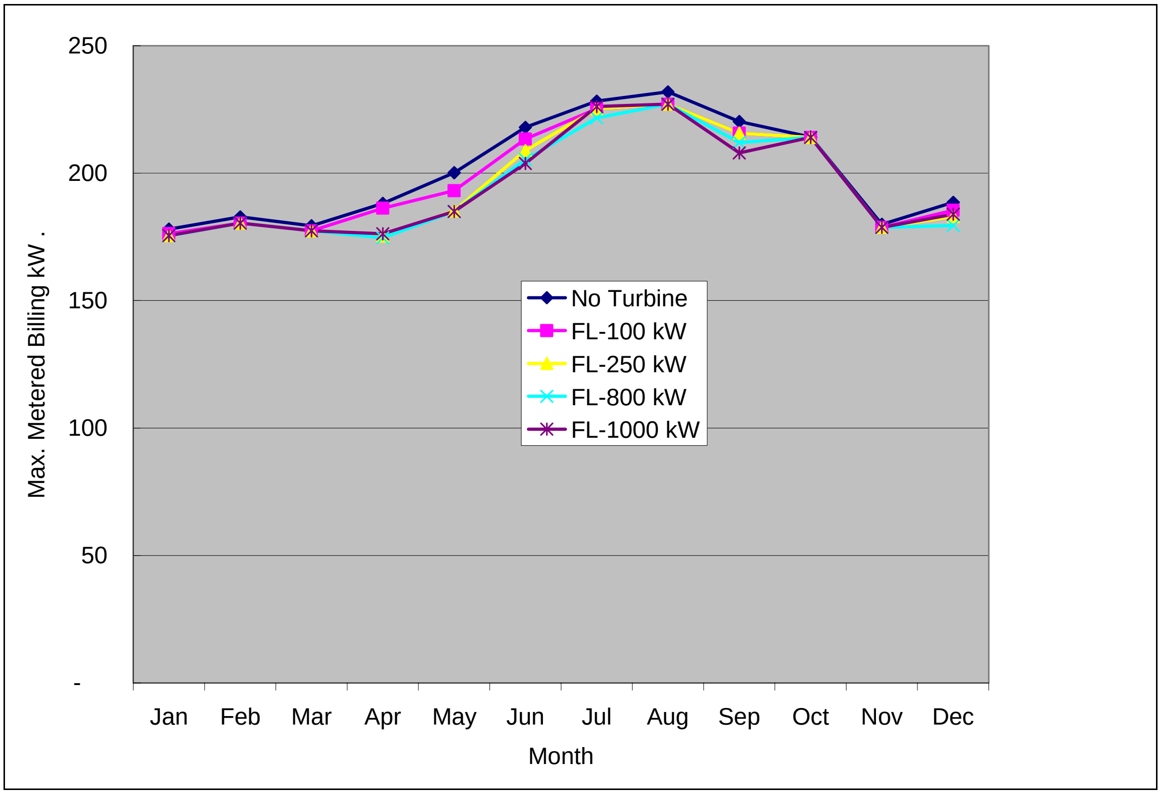

Exhibit 2 –
Current Distribution Energy Rates for the Commonwealth Territory

Period	# of Hours	G-2 Rate	G-3 Rate
Peak Load Period	1885	1.403 Cents/kWh	0.871 Cents/kWh
Low Load Period A	1769	1.120 Cents/kWh	0.771 Cents/kWh
Low Load Period B	5106	0.593 Cents/kWh	0.417 Cents/kWh
Total	8760		
Weighted Average		0.874 Cents/kWh	0.586 Cents/kWh

Exhibit 3 –
Comparison of Current and Proposed Distribution Charges for a Typical Commonwealth G-2 Customer for Various Turbine Scenarios

Wind Turbine Model	Rate Structure	Distribution Demand Charges	Distribution Energy Charges	Total Distribution Charges
FL-100 kW	Current	$3,246	$9,069	$12,315
FL-250 kW	Current	$3,210	$6,538	$9,748
FL-800 kW	Current	$3,189	$4,102	$7,291
FL-1000 kW	Current	$3,196	$3,234	$6,429
FL-100 kW	Proposed Standby	$10,615	$0	$10,615
FL-250 kW	Proposed Standby	$10,496	$0	$10,496
FL-800 kW	Proposed Standby	$10,427	$0	$10,427
FL-1000 kW	Proposed Standby	$10,449	$0	$10,449

Exhibit 4 –
Comparison of Current and Proposed Distribution Charges for a Typical Commonwealth G-3 Customer for Various Turbine Scenarios

Wind Turbine Model	Rate Structure	Distribution Demand Charges	Distribution Energy Charges	Total Distribution Charges
FL-100 kW	Current	$8,856	$35,412	$44,268
FL-250 kW	Current	$8,810	$33,372	$42,182
FL-800 kW	Current	$8,774	$26,502	$35,276
FL-1000 kW	Current	$8,738	$23,449	$32,188
FL-100 kW	Proposed Standby	$30,192	$0	$30,192
FL-250 kW	Proposed Standby	$30,034	$0	$30,034
FL-800 kW	Proposed Standby	$29,911	$0	$29,911
FL-1000 kW	Proposed Standby	$29,790	$0	$29,790

Exhibit 5 –
NEPOOL 2002 Marginal Emission Rates (Lbs. /MWh) and Potential Impacts of Wind DG with a 30% Capacity Factor

Emission	Lbs. / MWh	MWh / kW - 30% Capacity Factor	Potential Tons Reduction - 250 kW Turbine	Potential Tons Reduction - 1000 kW Turbine
SO_2	3.27	2628	1,074	4,297
NO_X	1.12	2628	368	1,472
CO_2	1,337.80	2628	439,467	1,757,869